CALIFORNIA
ENERGY
COMMISSION

RECOMMENDED CHANGES TO INTERCONNECTION RULES

In Support of 2005 Integrated Energy Policy Report

COMMITTEE FINAL REPORT

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Arnold Schwarzenegger, *Governor*

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DEDICATION

This report is dedicated to the memory of Joseph J. Iannucci, a true pioneer and visionary in the advancement of distributed generation.

ACKNOWLEDGEMENTS

The Committee recognizes the significant contribution of Rachel MacDonald, Darcie Houck, and Elizabeth Parkhurst in the preparation of this report.

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EXECUTIVE SUMMARY

On April 21, 2004, the California Energy Commission (Energy Commission) began an investigation to explore a variety of issues associated with the deployment of distributed generation (DG) including interconnection rules.

The purpose of this report is to recommend changes to California's interconnection rule for DG which is formally referred to as Rule 21. Rule 21 governs the process, schedule and fees associated with customers interconnecting DG to the utilities' power systems. Implementation of standardized interconnection rules has been an important priority for California because it eliminates a significant barrier to the safe and cost-effective deployment of DG in the State.

This document focuses on five key interconnection issue areas:
- Metering Issues
- Dispute Resolution Process
- Interconnection Fees/Costs
- Net Metering for Systems with "Combined" Technologies
- Interconnection Rules for Network Systems

These issues were debated extensively by the Rule 21 Working Group in September and October, culminating in the release of a Working Group paper on November 10, 2004. Additional feedback on the Working Group paper was provided to the Energy Commission's Integrated Energy Policy Report Committee (Committee) via comments on November 30, 2004 and a subsequent hearing held before the Committee on December 10, 2004.

Recommendations

Based on those deliberations, the Committee provides the following recommendations, with more details provided in the remainder of the document.

Metering Issues

- Net Generation Output Metering (NGOM) shall only be required when the customer receives publicly-funded incentives or tariff exemptions. It is unwarranted when less intrusive methods or cost-effective means of providing data are available, consistent with Section F.3 of Rule 21.

- The need for billing-grade or utility-owned meters is not always necessary. However, this issue may need revisiting if the frequency of billing disputes increase substantially. Additionally, costs surrounding billing disputes shall be recovered from distribution rates.

Dispute Resolution Process

- Modifications shall be made that will incorporate mediation from the California Public Utilities Commission's (CPUC) Energy Division, tighter timelines for review and resolution, and a clearer identification of technical and process decision-makers.

- Additionally, utilities shall be required to provide more detailed technical justification to the disputing party for requirements it proposes to impose, rather than simply relying on a general assertion of a need to protect safety and ensure reliability.

- Some level of information regarding disputes and their resolution shall be made available to the public for the purposes of learning and reducing frequencies of similar disputes in the future.

Initial/Supplemental Interconnection Review Fees

No changes to the fee structure are needed at this time.

An ongoing utility tracking and reporting system shall be established to provide detailed data on interconnection costs and assist regulators in making informed decisions regarding the future allocation of interconnection review costs. The costs of such a tracking system shall be recovered through utility distribution cost mechanisms.

Net Metering for Systems with "Combined" Technologies

Any methodology preventing export from the Net Energy Metered (NEM) generator while the non-NEM generator is operating is inappropriate. Doing so potentially reduces the economic benefit which the customer might otherwise enjoy under the NEM tariff, potentially reduces the efficiency at which the non-NEM generator operates, and runs counter to the state's need for additional generation.

Interconnection application fees and the costs associated with grid infrastructure improvements should be the responsibility of the utility, with the cost recovered through the distribution component of utility rates.

Interconnection Rules for Network Systems

The Rule 21 Working Group shall develop network interconnection rules that can be incorporated into the current framework of Rule 21. A report updating progress on this effort shall be provided to the IEPR Committee by December 2005, and will be part of this proceeding docket and CPUC Rulemaking R.04-03-017.

CHAPTER 1: INTRODUCTION

On April 21, 2004, the California Energy Commission (Energy Commission) began an investigation to explore a variety of issues associated with the deployment of distributed generation (DG). This report recommends changes to California's DG interconnection rule for DG, formally referred to as Rule 21. Rule 21 governs the process, schedule and fees associated with customers interconnecting DG to the investor-owned utilities' (IOU) power systems. Implementation of standardized interconnection rules has been an important priority for California because it eliminates a significant barrier to the safe and cost-effective deployment of DG in the State.

An industry group, referred to as the Rule 21 Working Group, was formed to develop the initial DG interconnection rules for California. This work was generally accomplished during calendar year 2000. The group now meets for the purpose of: 1) addressing more complex issues that have arisen; and 2) improving the interconnection process. Issues are debated and addressed in varying degrees. Resolution of such issues has often been reached. In some instances, however, additional policy direction from policymakers is required.

The Rule 21 Working Group includes representatives from all aspects of the DG community, with utility personnel, DG manufacturers, project developers, DG customers, and regulators. Approximately 35 members actively participate in regular meetings, held every 4-6 weeks. Another 200 members track developments via an e-mail distribution list. Updated materials related to the Working Group, including meeting minutes, Rule 21 equipment certification information, as well as technical documents are available on the Energy Commission website at:
[www.energy.ca.gov/distgen/interconnection/ interconnection.html]

The Energy Commission oversees the Working Group. Contract technical support is funded by its Public Interest Energy Research program. To date, approximately $1.2 million of public funding has been used to support the Rule 21 effort.

Development of this report was initiated by this Committee in an August 17, 2004 order which tasked the Rule 21 Working Group to develop an initial set of recommendations for Committee consideration. That report was completed on November 10, 2004. Public comments were submitted on November 30, 2004.

As the August 17, 2004 Energy Commission scoping order indicated, the Rule 21 Working Group was tasked with developing an initial set of recommendations to be evaluated by the Energy Commission's Integrated Energy Policy Report Committee (Committee). . A public comment period was held until November 30, 2004.

On December 10, 2004, the Committee held a hearing to further consider these recommendations. Participants representing utilities, equipment manufacturers, project developers and end use customers participated in a series of panel discussions on the five principal issue areas. The Committee has considered the testimony provided during this hearing and puts forth, in this report, the Committee's proposed recommendations.

These recommendations will be up for consideration by the Energy Commission at its February 2, 2005 business meeting. Prior to this consideration, parties will have an opportunity to submit written comments to the docket for 04-DIST-GEN-1 and 03-IEP-1. Comments are due January 20 by 5 p.m. and can be submitted electronically to docket@energy.ca.gov and stomashe@energy.state.ca.us.

Once adopted by the Energy Commission, the recommendation will be submitted to the CPUC in R.04-03-017. A final CPUC decision will follow after it develops a proposed decision, based on these recommendations. As agreed upon by the two agencies, the intent of parties commenting on the CPUC's proposed decision will not be to re-litigate positions expressed in the Energy Commission proceeding.

CHAPTER 2. METERING ISSUES

In this chapter, recommendations are provided on whether customers should bear financial responsibility for a meter and whether the utility should require customers to use a utility-supplied billing-grade meter on the customers' generation units. The focus of the metering discussion is on NGOM, which is a meter specifically designed to record the electrical production of a DG facility.

NGOM is defined in Rule 21 Section H to be the following:

> Metering of the net electrical power of energy output in kW or energy in kWh, respectively, from a given Generating Facility. This may also be the measurement of the difference between the total electrical energy produced by a Generator and the electrical energy consumed by the auxiliary equipment necessary to operate the Generator. For a Generator with no Host Load and/or Public Utilities Code Section 218 Load (Section 218 Load), Metering that is located at the Point of Common Coupling. For a Generator with Host Load and/or Section 218 Load, Metering that is located at the Generator but after the point of auxiliary load(s) and prior to serving Host Load and/or Section 218 Load.

Other terms such as *Net Metering*, *Net Energy Metering*, and *Net Generation Metering* have different meanings to different audiences. Therefore, NGOM will be used throughout to specifically refer to metering specifically designed to record the electrical production of a DG facility.

This issue is by far the most contentious in this proceeding. The Rule 21 Working Group began the debate in the summer of 2002 with the intent of resolving their issue under the current rule structure. However, the debate continues today and is clarified for the Committee's consideration. Table 1 contrasts the basic positions of the utilities and the position of the other parties in the proceeding.

TABLE 1
BASIC POSITIONS ON NET GENERATION OUTPUT METERS

Utility Positions	Positions of Other Parties
NGOM should be required for: 1) all new non-NEM interconnections, and 2) all facilities with multiple generators. Meters must be revenue quality, either utility-owned or third-party-owned meeting metering standards contained in Rule 22.	NGOM should be required when the customer receives publicly-funded incentives or tariff exemptions. NGOM is unwarranted when less intrusive methods or cost effective means of providing data are available. The need for billing-grade or utility-owned meters is not always necessary.

Recognizing the diversity of opinions, the following discussion expands these positions and provides a starting point to develop on the NGOM issue. In doing so, the Working Group asked the Committee to consider the following questions:

- Should NGOM be required in all circumstances, or should it only be required in some circumstances?

- When NGOM is required:
  1) Should the meter be of revenue quality?
  2) Can non-utility parties own the meter?
  3) Which party should pay for the meter?

- How can the policy considerations included in this proceeding be appropriately synergized with the CPUC cost-benefit analysis in R.04-03-017?

Metering, Monitoring and Telemetry conditions are currently addressed in Section F of Rule 21. As the section indicates, the utilities can require end-users to install NGOM equipment and specify the type. This requirement, however, does have its limitations. As the rule indicates, NGOM equipment can be required when "less intrusive and/or more cost effective options for providing the necessary Generating Facility output data are not available." The utilities must consider a variety of factors when determining the need for NGOM equipment, including the following:

- Data requirements in proportion to need for information,

- Producer's election to install equipment that adequately addresses the utilities' operational requirements,

- Accuracy and type of required metering consistent with purposes of collecting data,

- Cost of metering relative to the need for and accuracy of the data

- The generating facility's size relative to the cost of the metering/monitoring,

- Other means of obtaining the data (e.g., generating facility logs, proxy data, etc.), and

- Requirements under any interconnection agreement with the producer.[1]

Should NGOM Be Required in All Circumstances?

Circumstances Requiring NGOM Equipment

NGOM is explicitly required to comply with several statewide DG incentive programs. As explained below, the requirements for NGOM equipment are driven by the tariff-related provisions of the DG project, not the technical aspects.

Generating Facilities Receiving Standby Charge Exemptions

Section 353.15 of the Public Utilities Code, which contains specifications for generating units that qualify for standby charge exemptions, requires an ongoing evaluation of generator efficiencies, emissions, and reliability on an ongoing basis.[2] To perform this evaluation, the Code requires the customer to provide to the CPUC such information annually, recorded on a monthly basis. This information cannot be gathered without NGOM equipment.

Generating Facilities participating in the CPUC's Self-Generation Incentive Program (SGIP)

All SGIP participating generating systems are required to have electric NGOM.[3] The *SGIP Handbook* describes the required metering:

> Every system installed under the program shall be equipped with a dedicated, recording, time-of-use or interval meter to measure and record electrical generation output (i.e. Net Generation Output Meter). Many installations will require this type of electrical metering as a condition of interconnection with the utility grid. In the case of investor owned electric utilities, this means compliance with their filed CPUC Rule 21, Generating Facility Interconnections. (Handbook date 1/17/04, Revision 4, Section 5.2.1)

Additional metering is required for fossil fuel-fired generation participating in the SGIP. Fossil fuel-fired generators are to have supplementary metering to record waste heat utilization, and fossil and renewable fuel generators are to have metering to measure renewable fuel consumption. Based on the current SGIP reservation request form, the data from these meters are limited to program evaluation, measurement, and verification (EM&V). The cost of such metering is not paid for by the generator, but out of the EM&V budget.

Special Gas Rates

All cogeneration customers who take service under the gas rate that applies to gas-fired electric generation must meet operating efficiency requirements established under Section 218.5 of the Public Utilities Code. This operating efficiency standard requires data knowledge of each generator's net monthly kWh production. Additionally, utilities need monthly kWh production where the customer does not have a dedicated utility gas meter that measures only the gas input to the generator. Monthly kWh production is used to validate the amount of gas that qualifies for the cogeneration rate. This latter instance requires timely retrieval of the data by the utilities in order for timely and accurate bills to be presented to customers.

Certain "Net Energy Metering" Projects

Section 2827, 2827.8, 2827.9, and 2827.10 of the Public Utilities Code outlines basic metering provisions of NEM projects. These projects do not require NGOM, but they do have different metering requirements depending on the type and size of the generator. For further information, see Sections 2827.8, 2728.9, and 2827.10 of the Public Utilities Code. Also, see the utilities' individual "net energy metering" tariff provisions regarding metering.)

For most solar NEM customers, net energy is measured using a single meter which registers the flow of electricity in two directions. The utility has the option to install dual meters to provide the information necessary to bill or credit the customer accurately.[4] The expense for the dual meter depends on the type of project. In most cases, the utility is responsible for the cost of the dual meter, with the exception of NEM projects under the CPUC's pilot biogas and fuel cell programs. Metering required for these projects are specifically required to be revenue quality.

Combined Technologies

Under certain situations, the generating facility will require "revenue quality" metering to calculate the credits and charges for different rate treatments. This requirement is necessary when a NEM-eligible customer has a photovoltaic system in addition to a wind energy system with a capacity above 50-kilowatts (kW) or a biogas and/or fuel cell system with a photovoltaic system. In one example, a combined photovoltaic/wind energy system below 50 kW receives credits at the full retail price, while all other types of NEM systems i.e. Wind above 50 kW, biogas, and fuel cells, receive credits based on the generation component of the utility's retail rate only.

Circumstances That May Not Require NGOM Equipment

When NGOM is unavailable, existing utility tariffs have provisions for measuring and estimating consumption as the basis for billing non-bypassable charges (Departing Load, Tail Competition Transition, Nuclear Decommissioning, and Public Purpose Program). [5] If reliable metered consumption information is not available, the utility may use an estimate. In this situation utility tariffs uniformly state that the customer may choose one of two (or three, in SDG&E's territory) proposed methods to estimate the customer's consumption. For example, SCE's tariffs state that the Departing Load customer's monthly consumption estimate will be based on the customer's historical load at the time it discontinues or reduces retail service with SCE**,** using either: a) the customer's demand and energy usage over the 12-month period prior to the customer's submission of notice or b) the customer's average 12-month demand and energy usage, with such average to be as measured over the prior 36 months of usage.

Utility Positions

The utilities assert that Rule 21 gives them the discretion to require NGOM on generating units when they believe that metering is necessary for accurate billing or regional monitoring. SDG&E's position has been to require NGOM consistently on all customer generation. SCE holds the same position currently although it had previously allowed third-party metering and data collection arrangements for DG interconnections.

PG&E has prepared Appendix A to illustrate that NGOM, while not required for all generator installations, is required for four generator applications:

1. Generators qualifying for certain tariff exemptions by operating as a cogenerator in compliance with Public Utilities Code Section 218.5
2. Generators receiving a rebate under PG&E's Self-Generation Incentive Program;
3. Generators who are required to have a NGOM under Rule 21 Section F.5 (Telemetering)
4. Customers eligible for a standby waiver.[6]

In essence, the utilities believe that the alternative reporting requirements in Section F.3 are inadequate to let them effectively and accurately administer tariff provisions as well as to determine resource needs to provide safe reliable service to customers.[7] PG&E argues that non-metering alternatives produce information gaps and data integration issues, often requiring the need to input data manually. Additionally, PG&E points to customer inability to provide the necessary data in a timely manner or to provide data that is accurate or in a format that is readily useful for billing purposes. In some instances, PG&E notes that customers have simply refused to provide the data, indicating that the data is proprietary.

Along these lines, SCE cites the difficulty of re-integrating data because customers do not use a common format. Moreover, SCE states that some customers are averse to having tariffs administered by estimated usage and have complained about the utility estimates used for billing purposes. SCE further contends that, because of uncertainties in accuracy and the incompatibility of data formats, a billing-grade meter must be installed to measure the output of the customer's generator for acquiring data needed for the operation and planning of their electric systems.

Regarding the desire to use estimation as a regular billing feature in lieu of a meter, SCE asserts that estimation should be used sparingly, not in an ongoing manner and that eventually a meter read needs to be obtained. As SCE contends, customers often reject the estimated bills, requiring a different method to obtain usage and a need to often re-bill the account. This is an expensive, manual process.

Rule 21 does indicate that less intrusive and/or more cost effective options for providing usage can be used but the rule is silent on using estimation for an indefinite period. To do so, according to SCE, would be a violation of Section 770(d) of the Public Utilities Code. While tariffs and rules can be changed by Advice Letter, the Public Utilities Code can only be changed by Legislation. SCE concludes it would be inconsistent with Public Utilities Code section 770(d) to allow continuous estimation of usage for billing purposes.[8]

The Working Group notes that the CPUC is scheduled to submit a report to the California Legislature in January 1, 2005 on the costs and benefits of NEM per PUC 2827(n). This report, combined with the NEM limit, and other legislative proposals, may lead to changes in the NEM law for new projects. Issues to be addressed may include who pays non-bypassable charges on the NEM eligible generation serving a customer's on-site load and more importantly how it will be calculated.

If the California Legislature acts on this issue, the exemption status of NEM customers could change. SCE suggests that customers may no longer be exempt from non-bypassable charges on their generating facility's output serving on-site load, on a going forward basis, with the possible exception of NEM customers who meet the provisions of Public Utilities Code 2827.7. SCE also believes that even these Public Utilities Code 2827.7 exempt customers may not be exempt from all components of the utilities non-bypassable charges. Such a change in SCE's opinion would likely necessitate the need for generation output metering on all new NEM eligible generating facilities to calculate non-bypassable charges accurately.

SCE's justification to require the installation of NGOM may extend beyond tariff administration. The utility has indicated a desire to reserve the right to require them for system monitoring purposes.

DG Customer Position

Many non-utility Working Group participants oppose a blanket requirement for NGOM and also differ on the use of estimation. Their opposition is driven by both the additional cost imposed by such metering and the possible intrusion onto a customer's property resulting from such metering. Equally important to some DG customers is the concern that NGOM may be used by the utilities to gather customer confidential and commercially sensitive data.

In essence, these customers believe that NGOM is not necessary in all circumstances and should not be automatically required. They argue that CPUC-approved non-metering alternatives, when reliable metered consumption information is not made available should suffice for tariff administration purposes. This is particularly true where the customer does not choose to claim tariff exemption compensation for benefits put to the grid, if determined, or for incentive payments from statewide programs such as the SGIP.

The Rule 21 metering section defers to specific utility billing needs set forth in the specific tariffs for tariff administration needs, not the other way around. These parties also note that Rule 21 requires the utilities to first demonstrate a need for NGOM before mandating metering on the customer's side of the site boundary. These parties further point to the current language that indicates the utilities should only require NGOM to administer a tariff "to the extent that less intrusive and/or more cost effective options for providing the necessary Generating Facility output data are not available." Some DG customer groups further state that the Point Of Common Coupling metering provision provides the requisite metering configuration for retail service tariff administration (see Rule 21, Section F.4.)

In response to the utilities' complaints of data integration issues and billing complexity, non-utility parties maintain that these complaints do not justify the cost of or the intrusion into non-utility property caused by NGOM. Moreover, where a customer has not opted for the gas cogeneration rate or participated in the SGIP and chooses, as is the customer's right under utility tariffs, to have its bills based on estimated usage, NGOM is not necessary and should not be required. For example, as cited above, all three utilities' provide for the use of estimated consumption to bill Tail CTC, when reliable metered consumption information is not available. The CPUC has determined that this method is reasonable and has ordered the utilities to use it for billing the DL CRS.[9]

In a related matter, the DG customers disagree with SCE's interpretation of Public Utilities Code section 7 70(d) about the use of estimated meter readings for billing purposes, noting the specific use of different terms, i.e., "estimated consumption" as permitted by utility tariffs versus "estimated meter readings" referred to in the Public Utilities Code. Those DG customers believe that these authorities direct the utility when the existing utility meter cannot be read, because of weather or vandalism, rather than mandate a new metering requirement. In that instance, the meter reading may be estimated for that billing cycle.

Further, some of the DG Customers believe the CPUC has determined that such DL customers are responsible for certain non-bypassable charges and has also provided specific direction for utility billing of these charges. Many have concluded that the CPUC has determined that NGOM is not required for the calculation of the DL CRS. Contrary to SCE's argument that although the CPUC stated existing utility tariffs are sufficient for measuring and estimating departing load, it is silent that metering is specifically not required.

Relationship of Net Generation Metering at the CA ISO level to the Metering Issue

Notably, the Federal Energy Regulatory Commission (FERC) has ordered Qualifying Facilities (QFs) in California to use point-of-common coupling meters, forbidding the California Independent System Operator (CAISO) for using net generation meters.[10] The FERC has addressed the question of whether QFs in California must submit to a CAISO proposed requirement of NGOM. FERC ordered the CAISO to meter QFs only at the site boundary, stating that a requirement of gross metering ("net generation metering") was unfair and unnecessary. This decision binds QFs in California operating under a CAISO Tariff.

In Decision 01-07-027, the CPUC also found the CA ISO gross metering, (*i.e.*, NGOM) policy unsupportable. Although different terms are used, e.g., gross meter for net generation meter, some DG customers believe that the CA ISO gross metering proposal is equivalent to the "Net Generation Metering" defined in Rule 21. Some DG customers believe that the CPUC and the FERC have thus determined that NGOM is not necessary in all circumstances. The utilities, however, do not claim that NGOM is necessary in all circumstances and believe these decisions are not relevant here. In particular, they note that the issue in D.01-07-027 was whether the CPUC should support the ISO's claims at FERC that certain charges should be based on gross usage, an issue they believe is not relevant here.

Some DG customers contend that the planning and operation of the utilities' systems are impacted by: 1) the withdrawal or injection of power from or into their systems; or 2) the installed capacity of the customer generation. The electrical power withdrawal and injection is metered at the Point of Common Coupling and the installed capacity of the customer generation is reported as an element of interconnection with the utility. Accordingly, some DG Customers do not believe planning and operation concerns justify NGOM. Moreover, as noted by FERC in its Opinion No. 464, the WSCC witness stated, "[S]ince the implementation of PURPA, QF facilities have typically used [point of common coupling] metering" and he acknowledged that there had been no major system disturbances.[11]

If NGOM Is Required, What Grade of Meters Should Be Required?

Most customer generation facilities are supplied with a meter or other instrument to measure the amount of power produced by the generating facility. Such measurement devices may or may not be of utility grade accuracy but typically satisfy DG customer needs. The data provided by such metering is produced in various formats and quality.

Utility Position

The utilities assert that a revenue-quality meter is required for assessment of revenue-related costs, including customer responsibility surcharges such as public purpose program charges and nuclear decommissioning and other non-bypassable charges. The utilities in particular cite the need to assess these specific charges as a basis for requiring revenue quality meters. The utilities further contend that, due to the uncertainties in accuracy and the incompatibility of data formats, installation of a billing-grade meter is required to measure the output of the customer's generator for acquiring data needed for the operation and planning of their electric systems.

Rule 22's direct access provisions for electric meter service providers Meter Data Management Agent (MDMA) and the Direct Access Standards for Metering and Meter Data (DASMMD) could provide a model for establishing metering standards for third-party meters. Vendors could incorporate these standards as part of the DG configurations they supply to DG developers/customers. These meters would be of an Energy Commission/utility acceptable revenue-quality, utility-grade, alleviating the need to install a redundant utility meter adjacent to the vendor's meter.

Appendix B, prepared by PG&E, compares utility-supplied metering costs and functionality. The table includes the meter component only. Typical costs for meter installations, including mandated federal taxes vary depending on the voltage of the installation and the size of the generator. Typical costs for installations at the 0-600 Volt level would be approximately $1,500 while costs for a 21 kV installation would run approximately $15,000.

DG Customer Position

Some non-utility Working Group members respond to the utility position that the planning, operating, and billing accuracy needs mandate a billing-grade meter by again noting that the utilities' systems are impacted by: 1) the withdrawal or injection of power from or into their systems or 2) the installed capacity of the customer generation. The electrical power withdrawal and injection is metered at the point of common coupling and the installed capacity of the customer generation is reported as an element of interconnection with the utility. Accordingly, these parties assert that planning and operation concerns do not justify NGOM in the first place.

Moreover, a requirement for billing-grade meters, if DG developers and DG customers are financially responsible to install, maintain, and operate the meters, would add redundant costs as the DG systems already come with meters or measuring devices. DG manufactures and project developers believe that this requirement would increase the costs of DG systems and possibly inhibit DG development.

Pricing impacts and space constraints are important in of metering issues, particularly for 208 Volt and 480 Volt net generation output meter installations. In general, higher voltage utility metering sections can be much larger and more expensive than the items described below. For example, a revenue-grade metering equipment at a 13.8 kV level imposes an additional cost of approximately $30,000.

To provide some perspective on these issues, most DG applications are installed in existing buildings, with the cost and floor print of the meter sections to be reviewed. This is under review if the DG owner has redundant metering abilities installed on-site, and the utility meter appears redundant. The 200 ampere (A) in-line meters are small to install, and can be wall hung in a relatively small space. The equipment costs to install the meter panel can be approximately $1,500. The costs of the utility meter and fees can add an additional $2,500.

Meter installations of 400-800 A require an additional switchboard section that can add up to 38” of switchboard width, with the cost ranging from $2,000-3,000, with utility meter fees running an additional $2,500. Meters that are 1000-3000 A are even more expensive, sometimes being more than double the cost of 400-800 A meters.

Who is Responsible if Metering Is Required?

Some parties assert that they can install metering to meet the utilities’ and customer generators’ needs. All parties agree that this and the CPUC companion proceeding are the appropriate forums to consider any needed protocols for third party metering services based on Rule 22 metering service provisions. Notably for “net energy metering” projects, the Public Utilities Code establishes cost responsibility for additional meters. Similarly, CPUC Decision 01-03-073 states that the cost of monitoring SGIP program participants will be paid with SGIP funds.

Utility Position

The utilities believe that the costs of DG interconnection, unless waived by statute, should be borne by the DG customer because other ratepayers should not be burdened with another customer’s choice. However, metering for the SGIP, if not otherwise required, are paid out of the program budget rather than by the DG customer.

PG&E recommends that NGOM be required for all gas-fired cogeneration DG customers that qualify for PG&E's gas rate for electric generation (G-EG).[12] The IOUs would install and own the metering, with the applicant responsible for the cost. If the IOU only provides electric or gas service, if metering is required, the utilities prefer to own and operate the meters themselves, with the DG customers responsible for the costs of owning, operating, and maintaining the meters. The utilities are, however, willing to consider third-party provision of metering services if proper controls for DG customer data accuracy and security are implemented, and the utilities are able to integrate the data provided into the various utilities' billing systems.

If the CPUC reopens direct access in Rule 22, then vendors should be informed about the metering standards so that DG meters be revenue-quality, utility-grade (MDMA and DASMMD). This would alleviate the need to install a redundant meter.

The utilities recognize that the additional incremental cost to install utility-owned and-operated meters affect the economics of new DG installations. However, the utilities believe that the initial costs are insignificant to their on-going administrative costs and the host customers after customer generation is installed. At this time, significant technical and process hurdles must be overcome with any future third party ownership issues. Most important of these is the difficulty in electronically linking third party meters with, and the transfer of data to, utility billing systems efficiently. This means accurate and timely data management that minimizes resources, preserves customer confidentiality, and maintains data veracity.

PG&E is very concerned about the significant hurdles before future third party meter ownership, paramount of which is the difficulty in electronically linking third party meters with utility billing systems. As noted above, PG&E uses data from net generation meters for gas and electric billing, proper rate application, and compliance monitoring. According to PG&E, it is in the interest of all ratepayers to maintain accurate metering data. Therefore, PG&E recommends these meters not be installed or owned by third parties.

DG Customer Position

While some non-utility parties agree that Rule 22-type metering provisions would provide a basis for protocols for third party metering services, these parties assert that the current Rule 21 language already permits the CPUC to allow third-party provision of metering services for metering.

Some non-utility parties are concerned about the costs of a redundant metering requirement where a third party provider or customer has already installed a billing-grade meter. These parties believe that the current meter meets the utilities' specifications and allows access to tariff-approved billing data. For these customers, a utility-owned meter would impose an additional $4,000 - $10,000 to the installed cost per project.

Synergizing the Results of this Proceeding and CPUC Proceeding R.04-03-017

Much work is yet to be done related to the costs/benefit analysis conducted as part of the CPUC's companion rulemaking R.04-03-017. The ultimate metering needs for purposes to measure costs and benefits of DG properly are unknown at this time. Furthermore, the CPUC's advanced metering infrastructure proceeding (R.02-06-001) and advances in electric system operations may or may not require additional metering.

For these reasons, the metering recommendations contained in this report must be flexible enough to accommodate today's metering requirements as well as future requirements resulting from other proceedings that are not yet complete.

IEPR Committee Recommendation

In formulating its recommendation, the Committee reviewed the existing language in Section F.3 of Rule 21 and the extensive documentation in this proceeding. As a first order, the Committee agrees that NGOM is required when the customer receives publicly-funded incentive payments and/or specific tariff exemptions, but recommends that the CPUC clarify its intent for customers subject to the DL-CRS tariff.

Beyond these instances, however, the Committee does not believe that NGOM is required. This interpretation is based on current rule language which explicitly states that utilities shall only require NGOM to administer a tariff "to the extent that less intrusive and/or more cost effective options for providing the necessary Generating Facility output data are not available." The Committee shares the utilities' concern that the quality of the billing data using estimation may compromise the accuracy of the data and potentially increase the frequency of customer billing disputes. However, the customers' right to information protection outweighs this concern. If the frequency of billing disputes increases substantially, the Committee will revisit this issue. Additionally, the Committee recommends that the CPUC recover the costs surrounding billing disputes from distribution rates.

In situations where NGOM is required, utility-grade meters are not needed. Non-utility grade meters are acceptable, provided that the meters adhere to the direct access metering provisions outlined in Rule 22.

The Committee also recommends that the Rule 21 Working Group develop tariffs surrounding these recommendations should be developed by the Rule 21 Working Group and then submit to the CPUC via advice letter for approval no later than

September 1, 2005. The timing for this filing is important since there continues to be an ongoing sunset provision to key elements of the Metering section of the Rule 21. The current version of the rule calls for a December 31, 2005 sunset date.

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[1] Source: Rule 21, Section F.3.

[2] These requirements apply to generators above 10 kilowatts. Specific data required by the Code is paraphrased here and includes: 1) Heat rate for the resource; 2) kilowatt-hours produced during peak and off-peak periods, as determined by the California Independent System Operators; and 3) emissions data for the resource, as required by the Air Resources Board, appropriate air quality management district, or air pollution control district.

[3] The SGIP Handbook is developed through a Working Group process established by CPUC Decision 01-03-073 and provides implementation details for the program. The decision established the parameters of the required monitoring of SGIP participating customer generators, stating, "measurement and verification protocols established by the administrators include some sampling of actual energy production by the funded self-generation unit over a statistically relevant period." D.01-03-073, at 19. This decision then clarifies that program administrators, while required to monitor the extent of SGIP generator operation during peak hours, must use "independent evaluation consultants or contractors to develop a process for monitoring and collecting this data from program participants." D.01-03-073, at 32. These independent consultants are also supposed to install the hardware and software necessary, "not utility personnel." Id., at 20 (emphasis added). Moreover, it is those consultants or contractors, not the program administrators, who are to "present recommendations on incentive program designs that could improve on-peak load reduction from self generation." Id. The CPUC directed, "If the self generation unit does not already have built-in logging capability for this purpose [obtaining generation unit does not already have built-in logging capability for this purpose [obtaining operational data for evaluation], then the unit could be outfitted with a low-cost single-channel data logger and sensor (such as a relay switch) which would at least enable the utility to determine when the unit is operating and producing electrical output. Program administrators should develop and disseminate the specific requirements for system installations and monitoring capabilities required program evaluation" Id., at 33 (emphasis added).

[4] The utility can refuse the interconnection if the customer does not consent to install the dual meter.

[5] This information is referenced in SCE Preliminary Statement W, SCE Schedule DL-NBC, PG&E Preliminary Statement BB, SDG&E Electric Rule 23

[6] Attached Appendix A provides additional detail regarding PG&E's position on NGOM.

[7] SDG&E's shares its experience with a customer who is responsible for providing the required data. Since the beginning of the DG's operation in 2000, through current day, the data supplied to SDG&E: 1) is provided to SDG&E on a computer spreadsheet and is not verifiable by any other source; 2) is not in a compatible billing format so SDG&E must manually manipulate and input the data to its billing system; and 3) typically arrives later than requested. SDG&E concluded early on that alternative methods of obtaining meter data would result in difficulties and additional cost to SDG&E's ratepayers.

[8] SCE's Rule 9A Rendering of Bills states, in part, that bills for metered service will be based on meter registrations and meters will be read as required for the preparation of bills. Thus, each

month, with minor exceptions, SCE reads its customers' meters to determine the consumption from which to prepare monthly bills. If SCE is not able to read a particular meter, it is allowed to estimate the read and consumption for that billing period according to Rule 17A Estimated Usage. Rule 17A states, in part, that when accurate meter readings are not available, SCE may estimate the customer's usage on the basis of records of historical use. However, this estimation can only take place for one billing period without an actual read being obtained.

Code section 770(d) states, in part, that the Commission shall require any estimation that is incorrect to be corrected by the next billing period except for reasons beyond the utility's control due to weather or in cases of unusual conditions when such corrections will then be based on an actual reading following the period of inaccessibility.

[9] See Resolution E-3831. Opinion 3.

[10] The utilities disagree with the relevance of this section. According to SCE and PG&E, the FERC Opinion referenced is not relevant to Rule 21 or other retail tariff provisions.

[11] See 104 FERC ¶ 61,196, paragraph 39.

[12] PG&E's explanation for NGOM requirements are contained in Appendix A.

CHAPTER 3. DISPUTE RESOLUTION PROCESS

This chapter covers the dispute resolution process with principal focus on two questions:

1. Is the language contained in Section G of Rule 21 adequate to resolve differences between utilities, customers, or other parties planning, and designing DG installations?

2. Are other approaches preferable, i.e., the process adopted in the Massachusetts DG Investigation DTE 02-38-B?

Rule 21, Section G sets forth the following procedures for addressing disputes that arise under Rule 21:

- The CPUC has initial jurisdiction to interpret or modify Rule 21 or any interconnection agreements entered into under Rule 21 as well as resolve disputes regarding a utility's performance under its interconnection tariffs, agreements, and requirements.

- Disputes between a producer (*i.e.*, the entity that enters into an interconnection agreement with a utility) and a utility regarding the utility's performance under its interconnection tariffs, agreements, and requirements are to be resolved using the following procedures:

- The aggrieved party is to notify the other party in writing of the known facts relating to the dispute, the specific dispute, and relief sought, as well as express notice by the aggrieved party invoking the Rule 21 dispute resolution procedures.

- The parties must meet and confer to try and resolve the dispute within 45 calendar days of the date of the dispute letter.

- If the parties do not resolve their dispute within 45 calendar days, the dispute will, upon demand by either party, be submitted to the Energy Commission for resolution in accordance with the CPUC and the Energy Commission’s rules relating to customer complaints.

- Pending resolution of a dispute under Rule 21, Section G, the parties are to proceed diligently with the performance of their respective obligations under Rule 21 and any interconnection agreement.

Most parties believe that the dispute resolution process can be improved to some degree.

However, before addressing improvement SCE believes that the current dispute resolution process in California can also be used to resolve DG issues. A DG customer can file a complaint with the CPUC for any infraction of a rule or tariff. Thus, according to SCE, any infraction of Rule 21 can be resolved by the current dispute resolution process.[13]

Review of Other Approaches

The Rule 21 Working Group had suggested that the newly-developed Massachusetts dispute resolution process also be considered, but all parties currently reject this approach. The Massachusetts model, touted by many in the DG industry, has only recently been created and has not been utilized to date. Furthermore, the terms and conditions within that proposal add to the burden rather the making dispute resolution more efficient for all parties. Appendix C compares the general provisions of the Rule 21 and the Massachusetts processes as they currently stand.

A second approach was for a DG customer to approach the Rule 21 Working Group with an issue. PG&E’s position is that this option should not be formally incorporated into the Rule as a requirement, preferring it as an informal option for the customer. PG&E noted several problems with formally requiring this step in the Rule: not all DG customers have access to the Working Group meetings, whether for financial or time considerations, given that the meeting locations alternated among the utilities and the Energy Commission. Further, PG&E notes that the timing of the meetings, typically held once a month, might not allow time to consider a dispute. In addition, some issues are specific to the developer, not generic issues usually addressed by the Rule 21 Working Group.

Based on the above discussion, the Working Group does not suggest using an alternate approach to the existing dispute resolution process in Rule 21. However, there is potential room for improving the existing process, as evidenced below. Before beginning that discussion, the Rule 21 Working Group describes two brief case studies of two projects in the PG&E service territory where the process was invoked. Problems arising from that experience have largely influenced the recommendations contained in this section. The Working Group wishes to expresses its specific gratitude to RealEnergy, Tecogen, and PG&E for sharing their experiences in this report.

RealEnergy Dispute Resolution Experience

In early 2003, RealEnergy submitted applications for three projects to interconnect with PG&E's "spot" network in San Francisco. During interconnection discussions, PG&E consistently proposed requiring that 15 percent of the total nameplate rating of PG&E's transformer be imported during a building's minimum load period, but this requirement would have precluded RealEnergy from developing any projects in San Francisco.

The 15 percent requirement was not contained in Rule 21 or PG&E's Interconnection Handbook. In fact, Rule 21 provides, for radial systems, that the minimum power import requirement is five percent of the generating facility's gross nameplate rating.[14] In 2001, PG&E had previously applied the five percent generating facility standard to a RealEnergy “spot” network project in Oakland. No safety or reliability problems have arisen at this location.

Despite numerous requests from RealEnergy over an eight- month period, PG&E was unable to supply RealEnergy with a regulatory or technical justification for the 15 percent transformer input requirement or explain its rationale for seeking to impose different standards on similar "spot" network projects. On September 15, 2003, RealEnergy invoked the Rule 21 dispute resolution procedures and sent PG&E the required written notification.

RealEnergy and PG&E met and conferred within 45 days of the date of RealEnergy's letter. However, the process was not concluded until December 2003. RealEnergy did not file a complaint with the CPUC.

RealEnergy identified the following issues with the Rule 21 dispute resolution process as a result of its experience with PG&E:

- Time was wasted trying to ensure the appropriate utility staff participated in negotiations.

- The utility tended to interpret Rule 21, Section B.9 as imposing an inviolable duty to ensure safety and reliability, even in the face of verifiable data from the producer, a utility's technical staff, or consultant demonstrating a particular interconnection poses no threat to safety and reliability. The result was that Section B.9 became a barrier to entry.

- If neither party chooses to file a complaint, there is no timeframe for concluding informal discussions.

- Because filing a formal complaint is costly and time consuming, the current Rule 21 dispute resolution process effectively limits dispute resolution to informal discussion between the developer and the utility, and as such precludes development of a record for a neutral decision-maker through an interim process, such as CPUC Energy Division review, in cases where it may be useful to do so.

Tecogen’s Dispute Resolution Experience

Tecogen's recent dispute with PG&E began when PG&E rejected a group of Tecogen applications for "Simplified Interconnection" despite the full certification of the product and the site-specific Rule 21 screens being passed. Instead, the Tecogen applications were sent to "Supplemental Review" for further study. The applications were returned with a new requirement: each site would require a second and completely redundant system of safety relays that followed PG&E's own internal design interpretation and criteria. The situation affected about 24 units and 15 sites in the PG&E territory.

No resolution was forthcoming, despite numerous Tecogen/PG&E meetings and vigorous debate of the issue at the Rule 21 meetings. The requirement for the redundant system was crippling to the project costs, and Tecogen had little choice but to press for a more favorable outcome. Tecogen considered following the formal process of a CPUC complaint but decided to follow this route only as a last resort due to expense, time, and difficulty this would impose. In the end, after much internal discussion, Tecogen took the path of appealing to the highest management levels within PG&E; a letter outlining our position was sent to the PG&E board of directors. Consequently, a compromise agreement was reached that still required Tecogen certified units to have a redundant safety relaying system. However, the redundant system was a less costly one than originally specified by PG&E.

The entire process was unsettling in many ways. The time required caused extreme stress on the company financially (inventory expanded as units became stranded in the field and in the factory). PG&E was extremely slow in transferring the verbal agreement to paper (six months passed from our "handshake" to written one-page agreement). More importantly, the most progressive aspect of Rule 21, the creation of a system that allows type-testing and pre-certification for utility interconnection, had been severely undermined. Tecogen remains extremely concerned that the agreement will be undone by proposed changes being put forth by the utilities because of the low participation of non-utility entities in the Working Group sessions.

PG&E Response to the RealEnergy/Tecogen Comments

PG&E agrees that it has spent a good deal of time and energy in negotiations with RealEnergy and Tecogen, although it disagrees with specific statements by both parties. PG&E notes that it included a number of technical and management personnel in this dispute resolution process, because all affected projects were ultimately interconnected. One of the issues involved with RealEnergy was a technical issue concerning interconnection of DG with network systems, which many utilities across the country are now reviewing.

As Section V of this report correctly observes, there is a great deal of work that needs to be done concerning the installation of DG on such systems. PG&E is proud of the fact that it found creative ways of making DG work on such networks, and is learning as it moves forward. The utility does not believe that the resolution of disputes with either party in any way indicates the need for changes to the dispute resolution process under Rule 21.

Rule 21 Working Group Recommendations

The Rule 21 Working Group recommends several revisions to the Rule 21 dispute resolution process, affording parties a meaningful opportunity to resolve issues before resorting to the formal complaint process. Consensus recommendations support by all parties follow directly below. Recommendations offered without consensus are provided thereafter.

The Working Group suggests that the Committee consider the following points about these recommendations. First, the DG customer has little financial/time incentive to reach settlement from the utility prospective, while the opposite is almost certainly the case for the developer. Also, many of the dispute processes remain severely impeded by generalized and weakly supported utility arguments based on safety/reliability. From the utility perspective, legitimate reasons exist for treating the same type of DG installation uniquely in different locations, because of different loading and other factors concerning the distribution lines in the area.

Consensus Recommendations

The Working Group reached consensus on three recommendations.

First, upon receiving written notice that the Rule 21 dispute is being invoked, each party must designate one or more participating representatives with the authority to make decisions to resolve the dispute. Technical or support staff must be simultaneously designated to assist with that determination. However, the parties disagree about when such designations should occur. RealEnergy has proposed a five-day process whereas PG&E has suggested 10 days to ensure availability for an appropriate decision-maker. Tecogen also sees the value of a finite timeframe recommending a timeframe not exceeding 2-3 weeks. In addition, PG&E does not agree that it should be required to designate a technical or support person, let alone do that in five days. In many cases, PG&E does not believe that a technical person will be necessary.

Second, if parties are not able to resolve a dispute within an initial 45-day period, they may continue negotiations. Alternatively, either party may request in writing that the Energy Division provide assistance in resolving the dispute. The other party may also provide the Energy Division with its summary of the dispute. The Energy Division shall have 45 days from the date of the written request for assistance to meet with the parties in an effort to assist resolution of the dispute. This recommendation is supported by all parties. In addition, PG&E proposes to add the language in bold: "…. provide assistance in resolving the dispute, or, by mutual consent, parties can select a mediator."

Third, if the dispute may not be resolved with the assistance of the CPUC Energy Division, either party may file a complaint with the CPUC. All parties support this suggestion.

Disputed Recommendations

The Working Group could not reach consensus on three other recommendations.

First, the utility must provide the producer with reasonably detailed technical or regulatory justification for interconnection requirements it proposes to impose. It may not rely solely on a general assertion of need to protect safety and reliability as provided in Section B.9 of the Rule.

While RealEnergy and Tecogen support this recommendation, PG&E opposes this completely. According to PG&E, utilities must be free to justify technical requirements on the grounds that it is needed for safety and reliability when that is true. To do otherwise would gut their discretion to protect the system. Moreover, the purpose of dispute resolution procedures is to set forth substantive mandates for settlement. From PG&E's perspective, this recommendation is trying to write substantive Rule 21 interpretation guidelines into the dispute resolution which is inappropriate.

Second, to the extent the resolution of a dispute may have application with respect to future projects of the involved DG producer, the resolution shall apply to such future projects, unless the producer and the utility mutually agree otherwise.

Similar to the previous disputed recommendation, PG&E strongly opposes this recommendation because it believes it is impractical to suggest in the body of Rule 21 that resolution of every dispute with one generator can apply to all future projects. The utility argues that, because circumstances can change from project to project, depending on local line loading and design, and the technology involved, what happens to one project may not in fact resolve what happens to another project that may think it is similarly situated, but in fact it is electrically distinguishable.

Third, the results of each dispute resolved pursuant to Rule 21 shall be made publicly available.

RealEnergy and Tecogen strongly support this recommendation. The resolution should be precedent-setting for other projects that any reasonable third party would consider similar, especially in cases like Tecogen's where the dispute involves the applicability of Rule 21 certification and type-testing. Also, the utilities should have to present reasonable explanatory support of their arguments (rather than making blanket unilateral general assertions about safety and system reliability). The CPUC filing as the "court of last resort" is reasonable as is the need for dispute records to be publicly available.

PG&E's perspective differs on the recommendation. Absent signing a confidentiality agreement, customers are free to publicly disclose the fact that they have had a dispute with the utility. However, unless the customer has publicly disclosed such information, utilities are usually required to keep customer-specific information confidential. In most cases, disputes with utilities are resolved without the need for disclosing such customer information. PG&E believes that the CPUC should reject this proposal. Furthermore this recommendation runs counter to the CPUC's current rules on settlement of disputes (Rule 51) which recognize the important role of confidentiality in settlement discussions. If this recommendation is adopted, it will reduce the number of settlements and lead to more formal complaints.

IEPR Committee Recommendation

The Committee generally supports the three consensus recommendations of the Rule 21 Working Group. Regarding the first Recommendation, the Committee agrees with RealEnergy's suggested five-day process for notifying and designating participating representatives with the authority to resolve the dispute. This timeframe also includes the designation of support staff needed for assisting in that effort.

Regarding the second recommendation, the Committee supports a mutual arbiter, as suggested by PG&E, if both parties are amenable to such a designation. While generally endorsing the use of the CPUC's Energy Division to serve a similar role, the Committee recognizes the resource implications that this action may impose on the ability of the Energy Division to perform its other functions, and defers this option to the CPUC. The Committee also concurs with the third consensus recommendation that either party may file a formal complaint with the CPUC if a resolution via the Energy Division or a mutual arbiter cannot be reached.

With respect to the disputed recommendations, the Committee concurs with the DG developer community. The Committee strongly agrees that the utilities must provide reasonably detailed technical justification to the disputing party for requirements it proposes to impose, rather than simply relying on a general assertion of a need to protect safety and ensure reliability. The Committee does not accept PG&E's rationale that doing so would "otherwise gut their discretion to protect the system." Rather, a more detailed justification which provides the customer not only with information they are wholly entitled to, but also insight critical to that customer making effective business decisions.

Public availability of the results of such a dispute, as suggested by the DG developer community however, is slightly more complicated. As PG&E notes, customers are free to disclose the fact publicly that they have had a dispute with the utility. However, utilities are often required to keep customer-specific information confidential. The Committee believes that, in the case of interconnection disputes, there is precedent-setting value to some level of public disclosure. Doing so would disseminate lessons learned and reduce the frequency of similar disputes in the future. The Committee seeks additional guidance from the Rule 21 Working Group on balancing these mutual needs, including but not limited to developing an agreed-upon list of items that could be made publicly available.

Changes to Section G of Rule 21, consistent with the above recommendations, shall be developed by the Rule 21 Working Group within six months of a final CPUC decision and submitted by the utilities as an advice letter compliance filing.

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[13] SCE notes that the informal complaint process involves several steps all with the goal of resolving the complaint before it becomes a formal complaint. In 2003, SCE received approximately 4,000 informal complaints from customers with six becoming formal complaints. SCE continues by stating the other utilities have had similar successes with the process. The Informal Process involves supervisory review by the utility, review by the CSD Branch of the Commission's Energy Division, and combined review by impartial utility and CSD representatives which can also include mediation or arbitration at the customer's request. There are timelines for each step of the process with steps one and two being no more than 10 days and step three no more than 15 days. The Formal Complaint Process is handled by an ALJ pursuant to Resolution ALJ-1263 and the Commission's Rules of Practice and Procedure which have established time lines that result in a timely issuance of a Formal Complaint Decision.

[14] RealEnergy understands PG&E has prepared a white paper proposing standards for interconnecting projects to "spot" networks. It is not clear how PG&E intends to incorporate those standards into Rule 21.

CHAPTER 4. INTERCONNECTION INITIAL AND SUPPLEMENTAL REVIEW FEES

Chapter 4 addresses the need to revisit the fee schedule for connecting DG to the grid. Since Rule 21 was completely revised in late 2000, DG customers seeking to connect to the grid have been subject to a maximum fee of $1,400 as long as the project qualifies via the Initial or Supplemental Review process. The projects requiring little evaluation are assessed $800, with an additional $600 charged if some but not a substantial level of additional review is required. A project qualifying for interconnection under this provision is generally granted approval within 20 days, subject to a complete application.

More complex projects often fail the Initial and Supplemental Review processes, requiring a comprehensive review. Before doing so, the utility provides the customer with an estimate of the review and any approximate dollar amount for expected protection equipment.

When the fee schedules were adopted in late 2000, the CPUC and the Energy Commission assumed that the cost of reviewing the applications would decline over time as developers and utility protection engineers became more familiar with the equipment and the process for assessing DG interconnection. However, even in 2000, it was clear that the actual costs of processing the interconnection application exceeded the fee being collected by a significant amount.

Since 2000, the Energy Commission, under its FOCUS contract, analyzed the fee schedules to determine whether the time and cost of interconnection have declined as the new Rule 21 was implemented. For customers, the time and costs dropped significantly. Most interconnections are now achieved through either Initial or Supplemental review. The average time from application to interconnection dropped from 300 days in 1998 to less than 75 days in 2003, and continues to drop. The cumulative value realized from streamlining the interconnection process (years 2001-03) was over $20 million, largely from savings in time and reduced interconnection costs.[15]

Analyzing costs from the utilities' perspective was more challenging, with limited directive from the Energy Commission and the CPUC towards reporting the costs. In late 2002, the CPUC did order the utilities to track DG interconnection review costs. In early January 2003, all three utilities reported that the costs far exceed the fees collected. PG&E took this request one step further by creating an interconnection tracking system, which it continues to use today.

During the September/October 2004 meetings, the Working Group discussed PG&E's DG Interconnection Cost Matrix, shown in Table 2. The table describes what PG&E depicts as average interconnection cost data for 2004, annualized based on data through August 2004. As the table indicates, the average cost of an interconnection review varies widely, depending on the complexity of the project. For the simplest of the projects, a standard net metered project (i.e., PV on a residential home), the average cost of interconnection was less than $900. In contrast, traditional Rule 21 applications indicated in the last column average nearly $29,000.(It should be noted that the unit costs overstate the actual costs of a completed application since the numbers include costs incurred for all applications, including those that are withdrawn.) For example, for non-NEM applications, PG&E estimates that one-third of applications are withdrawn.

TABLE 2
PG&E DG INTERCONNECTION COST SUMMARY FOR 2004
TOTAL PROGRAM COST: $5,091,000

Rule 21 Technology	Administration	Engineering Review (Initial/Supplemental)	Pre-Parallel Inspections	Totals
Standard NEM Total Projects: 2,949 Total MW: 12.30	Cost: $1,263,000 $428 per project $102,683 per MW	Cost: $134,000 $45 per project $10,894 per MW	Cost: $1,150,500 $390 per project $93,53 per MW	Costs: $2,547,500 $864 per project $207,114 per MW
Expanded NEM Total Projects: 188 Total MW: 8.25	Costs: $312,000 $1,664 per project $37,818 per MW	Costs: $59,000 $315 per project $7,152 per MW	Costs: $88,500 $472 per project $10,727 per MW	Costs: $459,500 $2,451 per project $55,697 per MW
Non-NEM Projects Total Projects: 72 Total MW: 62.85	Costs: $1,192,000 $16,556 per project $18,966 per MW	Costs: $130,000 $1,806 per project $2,068 per MW	Costs: $762,000 $10,583 per project $12,124 per MW	Costs: $2,084,000 $28,944 per project $33,158 per MW

Notes on Table:

1) Data reflects PG&E's "Distributed Generation and Distributed Energy Resources OIR, DG Cost Benefit Analysis," testimony as filed in CPUC Rulemaking R.04-03-017, on 10/4/04.
2) The costs reflect actual DG-related interconnection costs tracked by PG&E from 1/1/04 through 8/31/04 normalized to calendar year 2004, up to the time of interconnection. Note that in 40 percent of the non-NEM projects, total costs include customer payments.
3) Administration costs reflect costs associated with the processing of the applications and requisite interconnection agreements, as well as the setting up of the billing and database tracking for NEM applications. Expanded NEM and non-NEM applications did incur additional costs for legal and tariff support activities in part because their larger size and higher likelihood of system impacts.
4) Costs associated with biogas NEM and fuel cell NEM applications are not addressed, nor are the costs associated with performing detailed interconnection studies, nor the costs for installing distribution system improvements and/or interconnection facilities.

The distinctions in cost among the Administrative, Engineering, and Pre-Parallel inspection were debated extensively. Some discussion focused on the pre-parallel inspection average cost of $10,583 and the rationale for the higher cost than the other two categories. PG&E indicated that it was often necessary to send utility representatives to multiple inspections for the same project, for a variety of circumstances sometimes under utility control, sometimes under customer control, and sometimes not under the control of either party. While PG&E's numbers provided a good starting point to start the discussion, many other parties believed that estimates were overstated for several of reasons. The Working Group expects the CPUC to address this issue in its hearings in R.04-03-017 in March 2005.

The debates also focused on the fee for interconnection: was it too low or too high? Did it encourage or discourage DG projects? How much time did the reviews take? Ultimate changes to the fee structure will likely require a revisiting of the fundamental issue about whether the interconnection review process should be subsidized by utility distribution customers as it is presently or whether the customer should bear the entire cost of the review. By virtue of the discussion in the Working Group meetings, many DG could not afford to pay the entire bill.

Rule 21 Working Group Recommendation

While some parties have declined to offer a specific position on the issue, the general consensus of the majority of the Working Group is that the fee structure should not change at this time. However, certain elements need further investigation, some to be undertaken as the CPUC considers the cost-benefit issue during the hearing phase of R.04-03-017.

PG&E suggests a change in the cost responsibility for pre-parallel inspections for Rule 21 non-NEM interconnections. From the previously submitted PG&E 2004 DG Cost Matrix, PG&E has expended significant resources for pre-parallel inspection activities. PG&E recommends a more equitable balance by requiring any pre-parallel inspections after the first attempt a responsibility the DG developer party. Other parties have objected to this recommendation, stating that it is not always the fault of the applicant when multiple pre-parallel inspections are made. PG&E agrees, and does not seek to charge the DG customer if the subsequent inspections are due to utility error. However, if the DG equipment is not ready for inspection when the utility sends its crews to inspect, then the DG customer or vendor should pay for the cost of that trip. PG&E's experience with non-NEM interconnections is that the customer is not typically ready to interconnect on the first inspection trip. Multiple trips contribute to the high per project cost for inspections reflected in Table 2.

To reconcile some of the concerns about PG&E estimates being overstated, it could be useful to develop a consistent tracking and reporting system to improve the value of the data going forward. Detailed data on interconnection costs will allow regulators to better understand cost causation and allocate these costs to the appropriate parties, depending on the results of the cost/benefit work currently being undertaken. However, a specific proposal has not been developed for discussion by the Working Group.

IEPR Committee Recommendation

The Committee believes that the $800 fee for initial reviews and $600 fee for supplemental reviews should continue without any modifications at this time. In reaching this conclusion, the Committee offers several observations. First, consistent with PG&E's data, the combined $1400 fee for the review does not fully recover the utility's cost of processing an interconnection application, however, the Committee notes that the fee was never intended to do so. In fact, the fee was designed to strike a balance between: 1) the DG developer, who need not face a significant barrier to developing a project from excessive fees; and 2) the utility that should not be subject to reviewing a multitude of applications for "speculative" projects.

In addition to these findings, the Committee notes PG&E's concerns regarding the added utility costs for multiple pre-parallel inspections. PG&E presented anecdotal evidence during the hearing indicating that 95 percent of the applications it has processed require multiple inspections, averaging four to five visits. SCE confirmed that many of its projects require multiple visits, but did not opine on the frequency of these occurrences. While the Committee believes that this issue is important for future consideration, there is simply not enough evidence to recommend an additional charge for multiple site inspections.

The Committee fully intends to revisit this issue in the future. In doing so, the Committee believes there is a need to establish a permanent framework for tracking utility interconnection application costs. We recommend that the CPUC require the utilities to develop a system, and that the costs associated with multiple reviews can be recovered through utility distribution cost mechanisms. As noted throughout this proceeding, PG&E has had a system in place since late 2002. The Committee believes that the utilities should implement the PG&E approach, and have the Rule 21 Working Group address the issue of consistency and reporting requirements during calendar year 2005. The Committee further expects the CPUC to address this issue more fully in R.04-03-017.

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[15] Source: *Making Better Connections: Cost Effectiveness Report on Interconnection of Distributed Generation in California Under the Revised Rule 21:* Energy Commission Publication 500-04-044, published July 2004.

CHAPTER 5. NET METERING FOR SYSTEMS WITH “COMBINED” TECHNOLOGIES

This chapter addresses the logging of costs of reviewing applications, metering requirements, and tariff administration associated with DG projects integrating both NEM and non-NEM generators. Based on extensive discussions, the Rule 21 Working Group offered the following conclusions and recommendations for the Committee’s consideration:

- Interconnecting multiple-technology generators on the customer’s side of the meter, whether for a generalized DG facility or a generating facility using generators eligible for interconnection under NEM tariffs, does not present any insurmountable technical obstacles to preclude the effective operation and protection of the utility distribution system.

- For cases involving multiple NEM generators allowed to export under different NEM tariffs, a metering solution may be workable, provided that tariff administration issues can be worked out.

- In the context of the Rule 21 Working Group’s review of a combined technology interconnection to the grid, policy guidance is required on the appropriate limits to be placed on exports from such a facility. Also, issues remain in the areas of tariff administration, equitable allocation of study costs, interconnection costs, and tariff charges.

- Policy issues remain to be resolved regarding how the legislature’s intent of the NEM program should appropriately be carried out, with respect to peak reduction, self-consumption, overall societal cost, and economic dispatch. The Legislature is scheduled to receive a report on January 1, 2005 from the CPUC addressing many of these issues.

The following discussion elaborates these conclusions and recommendations, offering potential solutions to the technical, contractual, and tariff-related problems of the combined technology interconnection.

Background Information

NEM customers that have a PV technology-based generator under 1 MW receive the following benefits under NEM:

1) Departing load, non-bypassable charges, and standby charges are not applied to the output of the generator.
2) Interconnection reviews are performed free of charge.

3) Credits for any power produced in excess of load during a year are applied at the full retail rates.
4) The two-way flow of power is unconstrained. Fuel cell and dairy biogas projects receive a credit for excess power based only on the generation component of their tariff. Dairy biogas customers also have the right to aggregate retail loads at other dairy operation related sites located on the same property to receive the benefit of the credit for excess generation.

Public Utilities Code Section 2827 does not address a customer who installs a qualified NEM technology with other non-NEM technologies, such as fossil fuel cogeneration. It also does not address how generators of two different technologies, each eligible for a different NEM tariff, are to be combined. The CPUC addressed this issue in principle in the previous DG rulemaking (R.99-10-025).[16] The CPUC argued that "integrated use of nonrenewable energy sources [does not exclude] eligible renewable generation connected to the same service account from net metering." The CPUC qualified this position by stating "the ineligible generator does not become eligible for net metering due to the combined configuration."[17]

To ensure that non-NEM generation did not receive the same treatment as NEM generation, the CPUC suggested that Option 1 of Rule 21 (i.e., use of a reverse power relay to ensure that power is not fed back into the utility grid) could be used to "[provide] adequate assurance that a nonrenewable generation system, even when connected to the same service account as the eligible renewable generator, will not export electricity."[18]

The Rule 21 Working Group has identified several scenarios under which a customer might submit an interconnection application, based on the sequencing of installations:

- The NEM generator was pre-existing and an application is made for a non-NEM generator.
- The non-NEM generator is pre-existing and application is made for an NEM generator.
- An application for NEM and non-NEM generators is submitted at the same time.
- Application is made requesting the utility to approve export from the site when the non-NEM generator is in operation.

Each scenario has unique ramifications with respect to the complexity of interconnection review, additional equipment and testing, and additional metering.

Metering and Tariff Considerations

Combined technology generating facilities may impose special metering requirements, beyond those that of a single-technology NEM, to ensure:

1) Only energy from an NEM generator is metered for credit;
2) Proper credit factors applied where different NEM rates are applicable;

3) That non-NEM generators are metered for tariff administration and distribution system monitoring; and
4) Biogas and fuel cell NEM, correct application of biogas generation credit against aggregated retail account.

It will also be necessary to ensure that other tariffs associated with the combined technology generating facility can be properly administered (e.g., standby and departing load tariffs applicable to non-NEM generation).

Technical Considerations

While CPUC decision D.03-02-068 addressed objectives to encourage NEM use while maintaining proper administration of tariffs for NEM and non-NEM generation, it did not address the technical aspects of coordinating protective devices for a combined installation. The Rule 21 Working Group has identified several issues related to assuring adequate protection.

When a customer installs any generator, it must interconnect in accordance with Rule 21. The application of Rule 21 leads to three general options for a customer: 1) install relays that will trip the cogenerator off before power is exported to the grid on more than a momentary basis, 2) show that the system design and customer loading will inherently yield negligible or no export and address safety concerns, or 3) pay and provide additional protective functions that permit safe operation in an export-to-the-grid mode (typically requires the ability to detect faults on the utility distribution system- normally a more expensive design than the two former designs). Regarding Option 1 above, it is essential for safety to utility's electrical workers and distribution system that the customer's non-NEM generator breaker trips open if export is detected for a period longer than the prescribed setting. This prevents the formation of an unintended island under a utility outage condition.

In the absence of a synchronous or induction generator, the certified anti-islanding inverters used in most NEM systems will shut down during a utility outage. However, it is possible that, in the presence of synchronous or induction generation, these combined technology systems may not detect the utility outage and cease production because they may not be able to differentiate between power supplied from the utility and power supplied from the cogenerator. This is a safety issue that must be addressed, with potential solutions discussed below.

Contractual Considerations

Contractual considerations must also be addressed. Existing CPUC-approved interconnection agreements for DG do not address generating facilities for which multiple tariffs apply. The Working Group believes that the principles in an interconnection agreement should include the following:

- Non-export (or inadvertent export) limits on non NEM generators should be maintained.
- Insurance provision for Generating Facilities with non-NEM generators should be included.
- Phased installation of NEM and non-NEM generators should be addressed.
- Review and facilities costs for non-NEM generation should be addressed.
- Departing load and standby charges applicable to non-NEM generators should be addressed.

The Rule 21 Working Group has facilitated the development of uniform contracts for several types of non-NEM DG facilities; the Working Group would be a useful forum to assist in the development of suitable agreements for combined technology NEM generating facilities.

Potential Solutions to Metering and Tariff Administration Issues

Given the myriad of NEM and non-NEM generating configurations, the four contractual scenarios should be used to address the issues. Table 3 provides a summary of each scenario, its rationale, and the issues surrounding implementation of the approach.

TABLE 3 POTENTIAL SOLUTIONS TO METERING AND TARIFF ADMINISTRATION ISSUES FOR COMBINED TECHNOLOGIES		
Scenario/Discussion	Attributes	Issues
1. Non-NEM May Not Operate During Export Under this approach endorsed by the CPUC, if the combined total generation of both NEM and non-NEM generators exceeded total on-site electrical load, the non-NEM generator would trip. Any export power metered at the Point of Common Coupling would, therefore, represent only NEM generation.	Consistent with CPUC guidance. Simple. One or more combined technology projects have been interconnected on this basis already.	This approach will guarantee that no energy from the non-NEM generator could be exported and receive the NEM credit. Under some circumstances, depending on the relative size of the eligible and non NEM generators, it could also prevent the export of NEM energy when the non-NEM generator is operating.[19] To avoid frequent nuisance tripping of the non-NEM generator, the customer can adjust its regulation to ensure that its output remains below the set point of the reverse power relay. This will also prevent the export of any NEM energy when the non-NEM generator is running. In a facility in which the non-NEM generator is relatively large, this approach could require that the non-NEM generator operates below its full design rating during the times the NEM generator was also operating. This could adversely affect project economics due to the less-efficient use of the non-NEM generator and additional demand charges. Also, this approach does not address the case of multiple generators eligible for different NEM tariffs, a case where all exports would be "eligible"—just treated differently for credits and retail load aggregation if dairy biogas.
2. NEM and non-NEM Generator: Allows export while non-NEM generator is operating, up to the limit of the output of the NEM generator. Allows export of energy and tariff credit up to the limit of the NEM generation when the NEM generator is operating. Non-NEM generator operates with trip or governor control to follow load and prevent export above NEM generator value.	Allows maximum size DG for a given site. Most cost-effective for customer generator.	May require extra meter costs, reconfiguration costs, spatial impacts, and complex generator controls. Depending on customer load and size of non-NEM generator, this scenario could still require that non-NEM be backed down to part load. Export limit should be the actual recorded energy produced by the NEM generator, rather than a fixed limit equal to its nameplate capacity.

TABLE 3 POTENTIAL SOLUTIONS TO METERING AND TARIFF ADMINISTRATION ISSUES FOR COMBINED TECHNOLOGIES		
Scenario/Discussion	Attributes	Issues
3. Two or more NEM Generators, Multiple Tariffs: Export allowed. For two generators, each eligible for a different NEM tariff, the task would be to distinguish between the exports from each to allow proper application of the differing credits and retail load aggregation (if applicable). This could be accomplished by metering each generator to determine its production.	Allows administration of different rates.	May require extra meter costs, reconfiguration costs, and spatial impacts. Tariff issues: Can a customer take service simultaneously under two NEM tariffs? Or must they choose one? Will the tariffs change over time?
4. NEM and non-NEM generator: Unrestricted export allowed while non-NEM generator is operating, using metering to determine amount of NEM energy to receive the NEM credit. The task would be to distinguish between the energy exported from the non-NEM and the NEM generator to allow NEM credit to be properly applied to the NEM generator only. This would require: a) metering of both the NEM and non-NEM generator; and b) adoption of a protocol to address the relative proportion of energy exported from the generators. In other words, energy from both NEM and non-NEM generators will serve customer load equally up to the point where total generation exceeds customer load. Exported energy will consist of energy from both generators, but should be apportioned to non-NEM and NEM rather than presumed to be all NEM energy.	Allows NEM and non-NEM generation to operate without curtailment, unlike Scenarios 1 and 2.	May require extra meter costs, reconfiguration costs, and spatial impacts. May also require different system protection. Could entail full-time export of energy from the customer's site, requiring greater complexity and expense of generator protection and interconnection facilities, and often may require a detailed interconnection study. Pro forma interconnection agreements for continuous export from non-NEM have yet to be developed. For the portion of exported energy that is non-NEM, this unscheduled, non-compensated energy would present a challenge to distribution system control, and possibly limit ability of utilities to procure energy and capacity from more environmentally benign sources. The prospect of unlimited energy exports also raises questions as to whether this type of generating facility would be "net energy metering" as contemplated in the NEM legislation.

Additional Considerations with Scenario 2

Under Scenario 2, the “stacking of resources” may make this type of project an export project rather than NEM. Stacking can be used to describe a situation which could occur where both NEM and non-NEM generators are operating and exporting power to the utility grid. The physical reality is that power exported consists of a mixture of electrons from both generators. When a metering or billing scheme is used that presumes that all exported energy comes solely from the NEM generator, the effect is that NEM generation is effectively “stacked” on top of non-NEM generation. This situation could occur because of the actual production of the new generator. The non-NEM generation is thus relegated to serving on-site customer load, while the NEM generation is reserved to obtain the NEM credit.

The utilities believe that proposed preferential “stacking” of eligible generation on top of non-eligible generation makes it a renewable energy *export* generating facility rather than a *net energy metered* generating facility. It would not necessarily “reduce demand for electricity during peak consumption periods” as encouraged by Public Utilities Code Section 2728 (a), especially since export is anticipated to occur during times other than utility peak load periods (i.e. weekends).

The City of San Diego has a different interpretation. It believes that the stacking order should allow the eligible output to create credits against other usage, up to the output of the eligible generator.   Using the current NEM, tariff a system may be sized at twice the actual load and the net production over a twelve month period will zero the customer usage from the grid. Any excess output over the *annual* usage creates no credit for the customer-generator.

These parties do not agree that resource stacking may encourage uneconomic dispatch. According to the utilities, allowing resource stacking proposed in Scenario 2 appears to encourage an uneconomic dispatch of generation resources from a societal standpoint by some customers. Instead of using solar or wind to serve on-site load first, at zero fuel cost, the customer would be encouraged to serve as much load as possible with fossil fired generation first to “save” renewable generation for export to maximize NEM credit. Moreover, current regulations governing the interconnection of customer generation do not impose any conditions on thermal efficiency, that the non-eligible generator could be non-cogeneration. The uneconomic dispatch inherent in this stacking approach also results in greater cost shifting to other utility customers because the effective cost of the “renewable” export energy (i.e. the full bundled utility retail rate) is typically higher than the cost at which utilities can procure renewable resources through a competitive solicitation process. The City of San Diego believes that the efficiency requirements of the cogeneration system would make the project economic compared to distant baseload plants with line losses considered.

Potential Solutions to Technical Issues

It is technically feasible to provide adequate protection and metering for all scenarios of eligible and non-eligible generators. As it exists, Rule 21 allows all interconnections of multiple tariffs to be evaluated. Each application to interconnect would be required to state what the existing condition is, NEM system already installed, and what the proposed change is, a non-NEM system to be installed. The utility review will evaluate the impact of the proposed change and prescribe the requirements for the change. Evaluation of multiple tariffs will often require a full interconnection study.

The Rule 21 Working Group has developed some preliminary concepts for reviewing and approving combined technology generating facilities even though the actual review of a project is site-specific and would also be affected by the actual sequencing of installation. The review depends on several variables, including the type of metering used by the NEM generator, whether additional protection is needed to accommodate the export or whether there is a need to limit the export, and whether the generating unit qualifies for simplified interconnection.

Policy Guidance Needed With Respect to Combined Technologies

Based on this discussion, the Working Group seeks policy guidance on two key areas.

First, is the CPUC policy in D.03-02-068 appropriate for interconnecting and metering combination of an NEM and a non-NEM generator with multiple tariffs? The utilities believe that, the CPUC's interconnection methodology is the most practical from the standpoint of balancing the interests of both the individual utility customer who installs the generators and other customers in general. Of the non-utility representatives actively involved in the Working Group, the City of San Diego believes that any methodology which prevents export from the NEM generator while the non-NEM generator is operating is inappropriate as it reduces the economic benefit which the customer might otherwise enjoy under the NEM tariff, and reduces the efficiency at which the non-NEM generator operates.

Regarding the second area, should customers who install combined NEM and non-NEM generating facilities be subject to interconnection review fees or study costs, costs for interconnection facilities or utility distribution system upgrades, and tariff charges (standby and departing load) which would otherwise be applicable to the non-NEM generator, in the absence of the NEM generator? The prospect of combining NEM and non-NEM generators in a single interconnection raises the issue of how to address the fact that NEM tariffs largely exempt customer from interconnection application fees, charges for interconnection studies and interconnection facilities, while non-NEM generators are not exempt from such charges. Setting aside the question of whether Rule 21's application fee structure reflects the utilities' actual costs in performing the interconnection reviews, the review work to interconnect the non-NEM generator in a combined technology project must still be done, regardless of the presence of an accompanying NEM generator.

The utilities generally agree that it is appropriate for them to collect application fees and other charges appropriate to non-NEM generators installed in combination with NEM generators set forth in Rule 21 and other tariffs. The City of San Diego suggests an alternative opinion indicating that the Legislature created laws that value DG and renewable generation as general benefit to the citizens. However, the intent of the DG legislation is being rendered uneconomic for many because of the incremental cost for interconnection issues and various tariff charges. The costs for infrastructure improvements needed (as determined by the local utility) to interconnect with the grid should be the responsibility of the utility with the cost recovered through rates.

IEPR Committee Recommendation

The Committee recognizes several viable technical configurations that a customer can undertake using NEM-eligible and non-NEM eligible technologies. The complexity of the configuration, however, is the administration of the utility tariffs. As indicated above, existing interconnection agreements and related tariffs do not address facilities where multiple tariffs apply.

In this regard, the Committee agrees with the City of San Diego and concludes that any methodology preventing export from the NEM generator while the non-NEM generator is operating is inappropriate. Doing so potentially reduces the economic benefit the customer might otherwise enjoy under the NEM tariff, potentially reduces the efficiency at which the non-NEM generator operates, and runs counter to the state's need for additional generation. On the latter note, the Committee disagrees with the utilities' notion that net metered projects are intended solely to reduce peak demand. The original intent of Section 2827 has changed since it was established in the mid-1990s. The permanent expansion of the net metering program consistent with the passage of Senate Bill 28X1 (Statutes of 2002) is testimony to this change.

Recommendations regarding the appropriate level of interconnection fees for combined technology projects are directly related to the Legislature's conclusion that clean and renewable DG benefits society. Based on this conclusion, the Committee recommends that the application fees and the costs associated with grid infrastructure improvements should be the responsibility of the utility, with the cost recovered through the distribution component of utility rates.

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[16] D.03-02-068

[17] Ibid, p. 61.

[18] Ibid, p. 61.

[19] The likelihood that this alternative will limit exports from the NEM generator depends on the relative sizes of generators and load, as illustrated in the following cases: 1) PV system & non NEM generator: The typical non-NEM generator in the marketplace today is of a larger capacity (kilowatts) than typical PV equipment. Use of a reverse power relay to trip the larger non-NEM generator will effectively result in no export. However, if the PV capacity exceeded the customer's load, this alternative would allow export of NEM energy. 2. Fuel cell-NEM and non NEM: Similar conditions as Case 1 above. 3. Biogas NEM and non-NEM: The generators typically used at biogas facilities tend to be of larger capacity than non NEM generators which might be used at the same facility. Under these parameters, if the biogas generator is larger than the customer's load, then there will be an export of NEM energy when the reverse power relay trips the non-NEM generator.

CHAPTER 6. INTERCONNECTION RULES FOR NETWORK SYSTEMS

This chapter deals with the need to develop rules to interconnect DG systems to distribution systems that have a network configuration. The Committee asked for the Rule 21 Working Group to address two specific questions:

1. What considerations should be given to developing simplified interconnection rules for networked systems in California?

2. What can be learned from experiences on this issue from other states and/or utilities?

The rules for interconnecting generating facilities to network systems differ compared with interconnections to radial systems. In a network system, technical requirements from the design and operational aspects of network protectors not employed on radial systems must be addressed.

In California, the major network systems are located in the metropolitan areas of San Francisco, Oakland, and Sacramento. Several DG projects have been connected to various network systems during the past few years. Due to the lack of clear technical information and guidelines though, many of these interconnections have been difficult.

Under the current screening process in Rule 21, interconnections involving network systems are advanced to the “supplemental review” stage. Because of the protective schemes used in network systems, most of the interconnections now require a detailed study. Without interconnection guidelines, utility companies now have to study each project and establish their own interconnecting requirements on a case-by-case basis.

Other Efforts Related to Network Interconnections

A number of focused efforts to develop network interconnection rules and guidelines are being undertaken throughout the country. The Massachusetts DG Collaborative is now meeting on this issue, pursuant to a directive by the Massachusetts Department of Telecommunications and Energy.

Similar to the Rule 21 Working Group process, the Massachusetts Collaborative holds regular meetings, provides background documentation, and is in the process of documenting the various network-related issues. They have also begun documenting network system installations of DG.[20] The group intends to address this issue through June 2005 and bring formal recommendations to its Board at that time.[21]

On the research side, the Energy Commission and the U.S. Department of Energy have already approved a new testing program to study network interconnnections. Testing will soon be conducted by Distributed Utility Associates (DUA) in California as part of the Distributed Utility Integration Test (DUIT) upon completion of the existing phase 1 testing. DUA plans to invite experts to a network interconnection meeting in New York during the next few months to discuss the issues and near-term solutions related to network interconnection, as well as to define the testing and test facility design that will be needed to further address those issues. DUA has developed a network primer that describes a network distribution system is, defines various components, and discusses the characteristics that pose a challenge to the interconnection of DG. The Committee understands the results of that work will be shared with the Rule 21 Working Group and others.

The Energy Commission PIER program is monitoring several DG systems to assess their impact on the grid and vice versa. This program will also include monitoring of actual DG connected to secondary network systems. Preliminary results are anticipated to be available in early 2005.

PG&E Guidelines for Spot Network Interconnections - California's Efforts Thus Far

With the largest network system in California located in the Bay Area, PG&E has taken initial steps to address the protection requirements surrounding network system interconnection. Its protection engineers have developed general guidelines, which can be developed more extensively through the Massachusetts and/or the California process. The utility notes that these interim guidelines will be thoroughly debated and may be modified in the future.

1. All of the network protectors on the Secondary Spot Network shall be replaced with Cutler Hammer CM52 network protectors equipped with MPCV relays.

2. Older style protectors (CM-22, MG-8, and CMD) may remain, provided that the network protector relays are replaced with MPCV relays or other PG&E-approved relays, capable of at least 2 set points, one with a time delay, and shall meet the following conditions:

    a) The Generator(s) plus the associated bus and/or cable to the main switch has a transient and sub-transient X/R ratio of nine or less for all operating scenarios.

    b) Synchronization of each generator shall be supervised by a PG&E-approved Sync Check relay.

    c) In non-fault conditions, the generator breaker must operate in 1.5 minutes or less.

d) Breakers separating all generation must open immediately without any intentional time delay under system fault conditions.

3. PG&E's planning engineer shall review network protector relays on the adjacent lines for relay coordination. If relay coordinations are inadequate, the old relays will be required to be replaced.

4. DG Producer will provide all necessary technical requirements as specified in Rule 21, including the protective device settings and frequency/voltage settings.

5. DG Producer will meet the minimum import requirements set forth below:

a) The DG may not operate Parallel Operation unless a minimum number of network protectors are closed. The DG must trip instantaneously when the number of closed network protectors falls below the following the value [select appropriate value from this table]:

Quantity of Network Protectors in Vault	Minimum Number of Closed Protectors Required in Order for DG to Operate
2	2
3	2
4	2
5	3

b) A minimum import setting of ten percent (10%) of the nameplate rating of the largest single network transformer serving the PG&E secondary spot network bus where the DG is installed. Minimum import protection is to be accomplished using a redundant PG&E-approved underpower (Device 37) relay or reversed power flow relay (Device 32). A meter with kVA summation of multiple services from the spot network bus is allowed on the common spot network bus through one or more generators. If PG&E's meters do not support summation and protection requirements, DG Producer shall be responsible for the cost of providing meters capable of supporting summation. If the minimum import is not met, the generator(s) must trip within 15 cycles to ensure that the generator(s) trip prior to the network protectors. Redundant protection of the net import minimum power must be provided.

c) A contact must be available on the existing network protectors to provide open/close status to the DG Producer's trip devices via a GE C-30 controller or PG&E approved controller will be borne by the DG producer. The DG cost for controller along with the installation and operating and maintenance costs of the relay/controller. The DG Producer shall install and terminate rigid grounded 2-inch conduit, and a pair of wires from the trip device to inside the transformer vault. The location of conduit core shall be reviewed and approved by PG&E.

d) DG Producer will provide 24VDC source from their battery with charging system for GE C-30 controller or PG&E approved controller. PG&E will do the installation of GE C-30 relay/controller or PG&E approved controller in the property owner's transformer vault.

Rule 21 Working Group Recommendations

The Working Group believes that much work needs to be done in this area and recommends that the Committee direct the Rule 21 Working Group to develop network interconnection rules that can be incorporated into the current framework of Rule 21. Any efforts undertaken in California could be coordinated with the work in Massachusetts and the DUIT testing facility. The Working Group understands that the Institute of Electrical and Electronics Engineers (IEEE) will begin the process of developing standardized network requirements in 2005 (IEEE 1547.6). In advance of that process, the Working Group estimates that preliminary Rule 21 requirements for network systems could be developed during the next 12 months. Once the IEEE standard is complete, which could take three to five years, Rule 21 will be revised consistent with the adopted IEEE standard.

If the Committee directs this approach, the Rule 21 Working Group offers a general outline to complete the task such as: 1) defining the issues (load, fault—Types: Spot, Area), 2) developing Supplemental Review information, 3) determining general requirements and including those results in section D of the rule, and 4) determining if opportunities exist for simplified interconnection (if so, include in section I). The Working Group offers the following eight-step approach.

1. Develop definitions, characteristics, and design philosophies for different types of networks to provide a common basis of understanding

2. Identify network systems in California
   - Locations
   - Physical characteristics

3. Identify the stakeholders nationwide who may be able to provide information
   - Utilities with network systems
   - DG suppliers
   - Customers on network systems who may be interested in DG
   - Regulators
   - Network equipment providers and other experts

4. Identify and investigate other projects and sources of documentation
   - DUIT proposed network meeting and network-related testing
   - FOCUS-III project monitoring network-system DG sites
   - Massachusetts DG Collaborative

- PG&E white paper and other technical literature
- IEEE Standard 1547.6 (SCC21 Chairman DeBlasio hopes to submit a Project Authorization Request to the IEEE board for this new activity in the first half of 2005)
- Manufacturer data sheets/white papers

5. Identify and investigate the availability of other rules and requirements

6. Identify and investigate existing distributed energy resources on networks

7. Identify problems and solutions
   - Experience from utilities
   - Experience from system integrators

8. Investigate costs of protection schemes and protector rework

IEPR Committee Recommendation

The Committee concurs with the recommendations of the Rule 21 Working Group. In doing so, the Committee endorses the eight-step approach noted above, with the expectation that the progress be provided to the Committee by December 2005.

The Committee fully intends to hold a public meeting soon after to discuss the report and provide guidance on recommended changes.

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[20] For additional information on the Massachusetts DG Collaborative, please reference the following websites: www.masstech.org/renewableenergy/public_policy/dg/meeting_index.htm, or www.masstech.org/renewableenergy/public_policy/dg/resources/network.htm.

[21] The Massachusetts DG Collaborative is part of the Massachusetts Technology Collaborative, the state's development agency for renewable energy.

CHAPTER 7. NEXT STEPS

The Energy Commission will consider these recommendations at its February 2, 2005 Business Meeting. Before this, parties will have an opportunity to submit written comments to the docket for 04-DIST-GEN-1 and 03-IEP-1. Comments are due January 20 by 5 p.m. and can be submitted electronically to [docket@energy.ca.gov and stomashe@energy.state.ca.us.]

If adopted by the Energy Commission, the recommendations will be submitted to the CPUC in R.04-03-017. A final CPUC decision will follow after a proposed decision is issued on these recommendations. As agreed upon by the two agencies, the intent of parties commenting on the CPUC's proposed decision will not be to re-litigate positions expressed in the Energy Commission proceeding.

APPENDIX A
PG&E Net-Generation Metering Issue – From Rule 21 Workshop/DG-OIR Proceeding

Area	Tariff	Need for Metering	Data Required for Frequency	Meter Ownership	Notes
Generator gas tariff administration	G-EG/PU Code 218.5	In order to determine compliance with tariff requirements and PUC 218.5	Total kWh (Monthly)	Utility (unless DG is located in muni territory)	Monthly kWh data is gathered in order to calculate monthly bills and calendar-year operating efficiency. Data is used to determine cogeneration in meeting the operating efficiency requirements per PUC Section 218.5
	G-EG/Rule 9	In order to ensure timely and accurate monthly gas bills.	Total kWh (Monthly)	Utility	In order to assure timely gas bills, data must be obtained on specified dates (that align with the gas meter read date) within monthly billing cycles and in a format agreeable to the billing system. For new generators that have no PG&E-owned dedicated gas meter, or where there is mixed gas end-use at a customer's plant, net meter data is used to ensure the correct amount of gas is billed under G-EG.
	G-EG/G-SUR Exemption	Ensure timely and accurate gas bills for mixed-usage customers, and ensure compliance with 218.5 and to correctly apply exemption from gas franchise fee surcharge established under G-SUR.	Total kWh (Monthly)	Utility (unless DG is located in muni territory)	G-EG customers that apply for cogeneration status are exempt from paying gas franchise fees under schedule G-SUR. Monthly data is required to correctly determine gas volumes that are exempt.
Standby Tariff Administration	Schedule S - Reservation Charge and Otherwise Applicable rate Schedule - demand charge	No metered data required, see Notes column	None	N/A	Standby demand charge waiver is provided under conditions of standby agreement (Form 79-280). Reservation Charge & Otherwise Applicable Rate Schedule demand charge
	Schedule S, Special Condition 7	Net generation profile is used to determine when customer is generating at above load requirement.	Net generation profile metering	Utility	This is an option under Schedule S. Customer opts to be billed for "supplemental" and "back-up" service.
	Schedule S and PUC Section 353	To determine compliance with tariff provision standby charges.	Total kWh (Monthly)	Utility (preferred)	Calendar-month kWh data is gathered annually in order to calculate monthly operating efficiency.
Non-bypassable charges (CTC, PPP, ND, TTA)	Preliminary Statement, BB and PUC Section 372	To determine compliance with tariff provision - exemption from CTC charges	Total kWh (Monthly)	Utility (preferred)	CPUC Resolution E-3831 and D. 03-04-030: method found in Preliminary Statement BB to be used to calculate departed load. However, for generators that meet only a portion of the load requirement, metering output is the most accurate means of determining departed load. Other interconnection scenarios (e.g. OTF, or where there is no load history) make this method meaningless.
Cost Responsibility Surcharges (CRS's)	E-DCG	To determine compliance with tariff provision - exemption from CTC charges, DWR Bond, DWR Power, and Regulatory Asset (RA). The RA will change to a Dedicated Rate Component (DRC) effective 2/1/05	Total kWh (Monthly)	Utility (preferred)	CPUC Resolution E-3831 and D. 03-04-030: method found in Prelim. Statement BB to be used to calculate departed load. However, for generators that meet only a portion of the load requirement, metering output is the most accurate means of determining departed load. Other interconnection scenarios (e.g. OTF, or where there is no load history) make this method meaningless.
Self-Generation Incentive Program (SGIP)		Annual efficiency calculation requires calendar month kWh net gen production.	Total kWh (Monthly)	Utility	Where required per the Self-Generation Incentive Program; and all costs borne by the SGIP
Distribution System Operation and Maintenance	Rule 21, Section F.5	Operation and maintenance of the distribution system requires knowledge of generator operation status	Net generation profile metering (data accessed in real time)	Utility	Telemetering required between generator metering and local distribution system operator, for customer generating facilities greater than 1 MW; or generating facilities greater than 250 kW on less than 10 kV systems.
Transmission System Operation and Maintenance	Rule 21, Section F.5	Operation and maintenance of the transmission system requires knowledge of generator operation status	Net generation profile metering (data accessed in real time)	Utility	Telemetering required between generator metering and local switching center, for customer generating facilities greater than 1 MW.

APPENDIX B
PG&E Rule 21 Metering Requirements (Non-NEM Projects)

Voltage Service	Generator Size	PCC Metering	PCC Metering Costs	Net Generation Metering	Net Generation Metering Costs	Phone Line Requirements
Transmission						
60kV & above Transmission	1 MW or greater	Bi-directional meter w/load profile modem & analog outputs	Bi-directional JEMSTAR meter cost - $1,900	Interval Meter w/modem	GE-kV type interval modem meter, cost - $400	Analog phone line
60 kV & above Transmission	100 kW to 999 kW	Bi-directional meter w/load profile and modem	Bi-directional JEMSTAR meter cost - $1,500	Interval Meter w/modem	GE-kV interval meter, w/modem cost - $400	Analog phone line
Primary						
50 kV & below Distribution	1 MW or greater	Bi-directional meter w/load profile modem & analog outputs	Bi-directional JEMSTAR meter cost - $1,900	Interval meter w/modem or mechanical meter w/detent to prevent reverse registration	GE-kV type interval modem meter, cost - $400 Elster mechanical ABS meter, cost - $170	Analog phone line
50 kV & below Distribution	200 kW to 999 kW	Bi-directional meter w/load profile and modem	Bi-directional JEMSTAR meter cost - $1,500	Interval meter w/modem	GE-kV interval meter, w/modem cost - $400	Analog phone line
Secondary						
Single-Phase New Installation	20 kW or less	Low-side metering	Residential meter type GE I-70S w/detent, cost - $30	Class 200 meter w/detent	Class 200 meter mechanical type GE I-70S w/detent, cost -$30	Not applicable
Three-Phase New Installation	21 kW t 199 kW	Low-side metering	Class 20 meter Elster type ABS w/detent cost - $155	Class 20 w/detent equivalent electronic	Class 20 mechanical Elster ABS series meter, cost - $155 Solid-state GE-kV meter, cost - $130	Not applicable

Table Notes:
1. Net generation metering will require instrument transformers depending on generator's output voltage and size of meter panel.
2. Customer is required to furnish necessary meter panel or switchboard with the instrument transformers usually furnished by PG&E.
3. Net generation and revenue metering installations should be a 4-wire system. Please contact Field Metering group during the early design process to prevent energization delays.
4. Customers with a demand of 200 kW or higher will require installation of an interval type meter with remote communication capability. The customer shall install, own, and maintain a separate, nominal 1 inch conduit and telephone cable extending from the meter panel location to the closest telephone service location. (Contact PG&E for specific requirements).
5. This matrix is intended as a quick information guide. This matrix does not supercede relevant tariffs, legislation, and CPUC decisions.
6. Costs are estimates of meters only. Other applicable costs for labor, ITCC and cost-of ownership charges would apply in accordance with Electric Rule 2.
7. Other metering configurations are possible, as approved by PG&E. For projects larger than 1 MW, the CAISO may impose additional metering requirements.
8. PG&E will install, own, and maintain all PCC and net generation metering unless directed otherwise by the CPUC. The PCC is the Point-of-Common-Coupling.

APPENDIX C
Comparison of Rule 21 and Massachusetts Dispute Resolution Process

Issue	Rule 21 Approach	Massachusetts Approach
Applicability	Current: Only utility; Proposed: Both utility and generator/customer	Both utility and generator
Overall Steps of Resolution	2 steps: (i) good faith negotiation; (ii) adjudicatory proceeding before the CPUC	Steps: (i) good faith negotiation; (ii) meeting before the Department; (iii) mediation; (iv) non-binding arbitration; (v) adjudicatory proceeding before the Dept.
First Step of Dispute Resolution		
-- What is it?	Good faith negotiation	Good faith negotiation
-- How is it initiated?	In writing by the generator (current) or either of the parties (proposed)	In writing by one of the parties
-- Who participates?	"Authorized representatives"	"Vice President or senior management"
-- How long does it last?	45 days	8 days
-- What happens if the step fails?	One or both of the parties may initiate step 2	One or both of the parties may initiate step 2
Second Step of Dispute Resolution		
-- What is it?	Complaint before the CPUC[22]	Meeting before a Dept. Hearing Officer or staff person to work out dispute
-- How is it initiated?	Current rules allow generators and customers (but not utilities) to make a written filing, in conformance with CPUC Rule 10	One party submits a written request with a summary of the dispute
-- Who participates?	CPUC ALJ, plus counsel from the parties	Dept. Hearing Officer or Staff Person, plus unspecified representatives from the parties
-- How long does it last?	Unspecified, except that an "expedited" process is available for small claims type issues in which a hearing will be held within 30 days	The meeting will take place within 14 days of the request
What happens if the step fails?	If one of the parties is dissatisfied with the Department decision and sufficient legal grounds for an appeal, the party may appeal the decision to state court	Step 3 is initiated
Third Step of Dispute Resolution		
-- What is it?	N/A	Mediation
-- How is it initiated?	N/A	Follows from step 2
-- Who participates?	N/A	A mutually-agreeable mediator; a mutually-agreeable technical expert (if needed); unspecified representatives from the parties
-- How long does it last?	N/A	Selection of mediator and technical representative will take 7 days; once commenced, it should be completed within 30 days
What happens if the step fails?	N/A	Step four is initiated
Fourth Step of Dispute Resolution		
-- What is it?	N/A	Non-binding arbitration (i.e., the mediator from step 3 issues a recommended resolution of the matter)

Issue	Rule 21 Approach	Massachusetts Approach
-- How is it initiated?	N/A	Follows from step 3
-- Who participates?	N/A	Same as under step 3
-- How long does it last?	N/A	Unspecified
What happens if the step fails?	N/A	If one of the parties does not accept the recommendation, then one or both of the parties may initiate step 5
Fifth Step of Dispute Resolution		
-- What is it?	N/A	Dept. adjudicatory proceeding
-- How is it initiated?	N/A	One of the parties must make a written request
-- Who participates?	N/A	(Similar to CPUC process)
-- How long does it last?	N/A	Hearings and Briefs are to be completed within 90 days; the Dept. is to decide the matter after an additional 20 days unless it extends this deadline
What happens if the step fails?	N/A	If one of the parties is dissatisfied with the Dept. decision and sufficient legal grounds for an appeal, the party may appeal the decision to state court

[22] CPUC Rules foster informal resolution. Rule 10 states, "A complaint which does not allege that the matter has first been brought to the staff for informal resolution may be referred to the staff to attempt to resolve the matter informally."